

**DIRECT TESTIMONY OF**  
**MATTHEW W. TANNER, Ph.D.**  
**ON BEHALF OF**  
**DOMINION ENERGY SOUTH CAROLINA, INC.**  
**DOCKET NO. 2019-184-E**

**TABLE OF CONTENTS**

<b><u>Description</u></b>	<b><u>Starting Page No.</u></b>
Introduction	2
Purpose and Summary of Testimony	3
Variable Integration Cost Study Background	4
Variable Integration Cost Study Results Summary	11
Variable Integration Cost Study Methodology	12
Variable Integration Cost Study Conclusions	20
<b><u>Exhibits</u></b>	
Resume of Dr. Matthew W. Tanner	MWT-1
Cost of Variable Integration for DESC Study	MWT-2

**INTRODUCTION**

**Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.**

A. My name is Matthew W. Tanner. I have been employed by Navigant Consulting Inc. ("Navigant") since 2012, where I currently am a Director in the company's Energy Practice. My business address is 1200 19<sup>th</sup> St. NW, Suite 700, Washington, DC 20036.

**Q. PLEASE SUMMARIZE YOUR EDUCATION AND EXPERIENCE.**

A. After graduating from Princeton University in 2004 with a Bachelor of Science in Engineering degree in Operations Research and Financial Engineering, I earned a Ph.D. in Industrial Engineering from Texas A&M University in 2009. I have over 10 years' experience in power systems modeling, economic analysis, utility resource planning, and Monte-Carlo simulation, which is a method to test a large number of random scenarios to evaluate the risk of an event occurring. My experience also includes evaluation of conventional and variable energy resources across North America and internationally, and the impact of these sources on electric reliability and cost of supply. A copy of my curriculum vitae listing my professional credentials and experience is attached as Exhibit No. \_\_\_\_ (MWT-1).

At Navigant, I lead our Wholesale Energy Markets group within our Energy & Capital Markets offering. I am responsible for advising utilities, state regulatory commissions, Independent System Operators ("ISOs"), developers, and other market participants on resource planning and strategy under uncertainty. I also have

1 led and supported multiple projects helping utilities and ISOs understand the  
2 challenges and changing requirements for power system resources as variable  
3 energy resource penetration increases. Navigant regularly consults for electric  
4 municipal and cooperative utilities, in addition to state and federal agencies. As a  
5 matter of practice, Navigant is committed to maintaining an independent and  
6 unbiased approach to its engagements.

7  
8 **Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT WITNESS**  
9 **BEFORE REGULATORY COMMISSIONS?**

10 A. Yes. Although I have not previously testified before the Public Service  
11 Commission of South Carolina (“Commission”), I have testified as an expert  
12 witness before regulatory commissions in other states on topics including variable  
13 energy resource integration and load variability.

14  
15 **PURPOSE AND SUMMARY OF TESTIMONY**

16 **Q. WHAT IS THE SCOPE AND PURPOSE OF YOUR TESTIMONY?**

17 A. The purpose of my testimony is to provide background and discuss the  
18 findings and conclusions contained in the August 2019 Navigant study titled “Cost  
19 of Variable Integration” (the “Study”) that was prepared on behalf of Dominion  
20 Energy South Carolina, Inc. (“DESC” or the “Company”). A copy of the Study is  
21 attached to my testimony as Exhibit No. \_\_ (MWT-2).

1 **Q. HOW HAVE YOU ORGANIZED YOUR TESTIMONY?**

2 A. My testimony is organized as follows:

- 3 • First, I provide background on the key concepts and definitions that are  
4 useful to understanding the operating challenges that variable generation  
5 causes for utilities and how mitigating those challenges adds costs.
- 6 • Next, I summarize the results of the Study.
- 7 • I then explain the methodology Navigant used to develop the estimates of  
8 variable generation uncertainty, the analysis of the additional required  
9 reserves, and the forecast of the additional system cost from maintaining  
10 these reserves.
- 11 • Finally, I explain in greater detail the results of the Study and how Navigant  
12 developed the conclusions.

13  
14 **VARIABLE INTEGRATION COST STUDY BACKGROUND**

15 **Q. ARE THERE CERTAIN TERMS AND CONCEPTS THAT ARE USEFUL**  
16 **TO UNDERSTAND THE OPERATING CHALLENGES AND COSTS FOR**  
17 **INTEGRATING VARIABLE GENERATION ON THE DESC SYSTEM?**

18 A. Yes. As part of my testimony, I use certain terms and concepts based upon  
19 the below descriptions and definitions:

- 20 • “Operating Reserves” means the capability of the electric system to quickly  
21 increase generation either by turning on quick-start electric generating units  
22 or ramping up the generating output of units that are currently online but not

operating at full capacity. Available operating reserves are calculated in terms of how much additional generation is available in a given period of time. Operating reserves are needed by an electric system in order to respond to unexpected drops in generation or unexpected increases in load.

- “Variable Integration Cost” is the increase in costs to an electric system as a result of the need to react to unexpected changes in renewable generation.
- “Renewable Forecast Error” is the variance between the planned renewable generation and the actual renewable generation.
- “Plant Cycling” is the act of turning an electric generating plant on and off in response to the need to meet load.
- “Quick-start Resource” is an electric generating plant that can turn on quickly allowing it to provide operating reserves even when offline.
- “Ramp Up/Down” is the act of increasing or decreasing generation at an electric generating plant.
- “Production Cost Model” is a class of energy system models designed to simulate detailed system operation and costs over time.

**Q. WHAT IS THE SCOPE AND PURPOSE OF THE STUDY?**

A. Navigant conducted the Study in order to estimate the impacts that solar installations will have on DESC’s system operations and to determine the resulting

1 incremental costs for projects that are already under contract and have a variable  
2 integration charge clause in their power purchase agreements (“PPA”).

3 To do this, the Study evaluated the Variable Integration Costs for two  
4 different scenarios of solar generation installed on the system. These scenario  
5 assumptions were developed to generally correspond with the amount of  
6 interconnected solar generation with PPAs that do not include a specific variable  
7 integration charge clause and the tranche of solar with PPAs that do have a specific  
8 variable integration charge clause. This is described in more detail by Company  
9 Witness Eric Bell. The specifics of the Study scenarios are shown in Table 1 below:

10 *Table 1. Assumed Solar Generation on DESC System*

<b>Solar</b>	<b>Maximum Nameplate Facility Rating (MW)</b>			
	2020	2021	2025	2030
<b>Utility – Initial Solar Case</b>	<b>336</b>	<b>340</b>	<b>363</b>	<b>404</b>
<b>Utility – All Solar Case</b>	<b>1,044</b>	<b>1,048</b>	<b>1,071</b>	<b>1,112</b>

11  
12 The study also describes how the additional reserve requirements for DESC  
13 that are caused by solar can be incorporated into the avoided cost methodology in  
14 the future.

15 Finally, the study describes the requirements that solar projects must meet in  
16 order to avoid the need for DESC to implement additional reserve requirements.  
17  
18

1 **Q. WHAT ANALYSES DID NAVIGANT UNDERTAKE IN PERFORMING**  
2 **THE STUDY?**

3 A. The initial analysis focused on establishing a benchmark for Navigant's  
4 PROMOD® production cost model that reflected DESC's actual system operating  
5 experience and the Company's own internal planning. The purpose of this initial  
6 analysis was to provide an appropriate and reasonable estimate of the Variable  
7 Integration Cost.

8 Next, Navigant conducted a solar uncertainty analysis, which estimated the  
9 forecast error for hourly generation from solar. The purpose of this analysis was to  
10 determine the amount of operating reserves that must be maintained by the  
11 Company in order to ensure that DESC can reliably respond and meet system needs  
12 if actual generation is less than forecasted.

13 The analysis then considered the challenges the Company would experience  
14 if additional reserves are not added to the system. The Study provides examples and  
15 analyses of time periods when DESC operators would experience insufficient  
16 amounts of resources that would be needed to maintain system reliability.

17 Finally, the Study evaluated alternative approaches to providing the  
18 necessary reserves including an analysis of the potential and cost to add new  
19 resources to the system as an alternative mitigation option. This involved estimating  
20 the Company's cost to maintain additional reserves necessary to integrate the  
21 variable energy generated by solar facilities. The other approach considered in the  
22 Study is the ability of solar projects to provide sufficient flexibility so that DESC

1 does not have to add reserves. The study identifies measures that could be  
2 implemented to possibly reduce the impact of a project on DESC's reserve  
3 requirements.

4  
5 **Q. HOW DOES THE VARIABILITY OF SOLAR GENERATION CAUSE**  
6 **ADDITIONAL OPERATING ISSUES FOR DESC?**

7 A. The amount of solar energy that can be generated is significantly impacted  
8 by and dependent on the weather. Therefore, there is inherent uncertainty in how  
9 much electricity is actually generated by solar generating facilities. In order to  
10 operate a safe and reliable electric system, DESC operators must closely match  
11 generation and load at all times. If there is forecast error and less solar generation  
12 than expected, then DESC must have the ability to ramp up other generating  
13 facilities to replace the lost solar energy.

14 This ability to ramp up generation over a given time period is a component  
15 of operating reserves. Operating reserves are maintained either by keeping  
16 generators online but operating at less than their full capacity or by maintaining  
17 quick-start generating resources. DESC operators also have to balance the need to  
18 meet its load and to maintain sufficient operating reserves with the goal of operating  
19 its system in a reliable and efficient manner.

1 **Q. HOW DOES SOLAR GENERATION RESULT IN ADDITIONAL COST TO**  
2 **DESC'S SYSTEM?**

3 A. When solar generation is added to the system, DESC's operators must  
4 maintain additional operating reserves in order to ensure that if less solar generates  
5 than expected, the system can respond. This adds cost by one of two ways:

- 6 • The system operation must be changed from its previous minimum cost  
7 dispatch and operate less efficiently so that additional operating reserves are  
8 available to meet unanticipated changes in solar generation, thereby  
9 increasing variable operating costs.
- 10 • The Company must add new resources to its system to maintain sufficient  
11 operating reserves to meet these needs, resulting in additional capital cost  
12 expenditures.

13  
14 **Q. DID THE COMPANY'S AVOIDED COST CALCULATIONS PRIOR TO**  
15 **THIS PROCEEDING CAPTURE THESE ADDITIONAL COSTS**  
16 **ASSOCIATED WITH THE ADDITIONAL RESERVES REQUIRED TO BE**  
17 **MAINTAINED AS A RESULT OF THE VARIABILITY OF SOLAR**  
18 **GENERATION?**

19 A. No. The Company's previous avoided cost methodology and calculations  
20 did not capture additional costs associated with the additional reserves required to  
21 be maintained as a result of the variability of solar generation. The Navigant Study  
22 evaluates the additional integration costs incurred by DESC to ensure the Company

1 can reliably operate its system considering the potential for solar forecast error. In  
2 this Study, Navigant was careful to design the Study methodology and analysis to  
3 be consistent with the Company's prior avoided cost methodology and calculations  
4 on which the Company's prior power purchase agreements were based and to  
5 prevent double counting of DESC costs.

6  
7 **Q. HOW CAN THE RESERVE REQUIREMENTS FOR SOLAR BE**  
8 **INCORPORATED DIRECTLY INTO THE COMPANY'S AVOIDED COST**  
9 **CALCULATIONS?**

10 A. The Company's avoided cost calculations are completed using a production  
11 cost model similar to what is used in this Study. In the future, when completing the  
12 avoided cost studies, DESC's model will properly reflect the reserves required as a  
13 result of the variability of the solar resources.

14  
15 **Q. HAVE OTHER UTILITIES ESTIMATED THE INTEGRATION COST FOR**  
16 **VARIABLE GENERATION?**

17 A. Yes. In recent years, other utilities including Duke Energy Progress, Duke  
18 Energy Carolinas, PacifiCorp, and Idaho Power, have estimated variable integration  
19 costs on their systems. Additionally, ISOs such as NYISO and PJM have conducted  
20 variable integration studies to understand what operation impacts (such as additional

ancillary service procurement) might be needed to ensure reliability given increasing levels of variable generation on the system.

#### **VARIABLE INTEGRATION COST STUDY RESULTS SUMMARY**

##### **Q. WHAT ARE THE STUDY'S FINDINGS AND CONCLUSIONS?**

A. Navigant's findings and conclusions can be summarized as follows:

- The solar generation being added to DESC's system is a variable resource and adds uncertainty to the generation needed from the rest of the system.
- DESC needs to maintain additional operating reserves in order to ensure that load and current reserve obligations are met. Without these additional operating reserves, there will be an unacceptable number of hours where DESC will face a shortfall in its available operating reserves.
- The levelized cost of maintaining additional operating reserves for the tranche of roughly 700 MW of solar generation that have a variable integration charge clauses in their PPAs is \$4.14/MWh for the All Solar Case.
- Building additional resources such as battery storage or quick-start gas combustion turbines solely to provide reserves will not reduce costs to DESC due to the additional capital cost currently required for these facilities.
- With the installation of co-located batteries or changing operation to be more flexible, as long as certain requirements are met, solar projects can be added to the system that do not increase reserve requirements.

1 These conditions need to be defined in detail but broadly require that:

- 2 ○ DESC has some ability to control the dispatch of the generation from
- 3 the project.
- 4 ○ Be able to replace enough of the nameplate capacity of the project
- 5 when called upon to make up for generation lower than forecasted.
- 6 ○ Be able to maintain the replaced generation for sufficient time to avoid
- 7 reliability challenges.

8

9 **VARIABLE INTEGRATION COST STUDY METHODOLOGY**

10 **Q. WHAT APPROACH DID NAVIGANT FOLLOW TO DERIVE ITS**

11 **FINDINGS AND CONCLUSIONS?**

12 A. A detailed description of the Study assumptions and methodology are

13 provided in the report attached to my testimony as Exhibit No. \_\_\_\_ (MWT-2). The

14 key aspects of the approach are summarized as follows:

- 15 1. Navigant benchmarked its PROMOD® production cost model to DESC's
- 16 system using information provided by the Company in order to provide a
- 17 baseline for the analysis. The baseline for each solar penetration scenario
- 18 reflects system operation without requiring any additional reserves to be
- 19 maintained.
- 20 2. The solar forecast uncertainty was estimated by comparing solar forecasts
- 21 with actual solar generation from the National Renewable Energy Lab's solar
- 22 integration dataset. Solar forecast uncertainty was calculated as the variance

1 of the 15-minute average of actual solar generation from the 4 hour-ahead  
2 forecast. Using this information, Navigant calculated the probability of how  
3 much less than expected solar facilities actually generate, which varies  
4 depending on the forecasted level of solar generation.

5 3. Navigant forecasted the challenges to DESC's system operation as a result  
6 of this variability in solar generation by determining the hours in which  
7 system operators would be unable to maintain the current required level of  
8 reserves if solar missed its forecast by the amount estimated in step 2  
9 described above. The hours demonstrate that DESC needs to maintain  
10 additional reserves to safely and reliably operate its electric system in light  
11 of the variability in solar generation.

12 4. The level of additional reserves that DESC needs to maintain was calculated  
13 as the maximum amount per day that solar could underproduce the forecasted  
14 amount.

15 5. Using PROMOD®, Navigant simulated system operation and production  
16 costs with additional reserves maintained by DESC. The difference in  
17 production costs is the integration costs attributable to the solar generation.  
18 Navigant then levelized the solar generation integration costs to create a  
19 \$/MWh value.

20 6. Navigant evaluated the effect of adding battery storage and gas combustion  
21 turbines to DESC's system as alternative mitigation options in order to  
22 determine whether adding these types of resources could reduce the

1 Company's system costs instead of simply maintaining operating reserves  
2 based on DESC's current resource mix.

3 7. Navigant evaluated the operating characteristics that would be necessary for  
4 a solar project to not increase DESC's reserve requirements.  
5

6 **Q. PLEASE DESCRIBE PROMOD®.**

7 A. PROMOD® is a widely-used industry-standard production cost model  
8 developed and licensed by ABB Ventyx. The PROMOD® modeling software is  
9 programmed to develop a low-cost energy supply solution for system load while  
10 also providing the required level of operating reserves and regulation. PROMOD®  
11 then simulates the balancing of resources to load on an hourly basis in order to  
12 generate a time-series optimized portfolio or unit commitment and dispatch  
13 optimization. In this manner, PROMOD® is able to simulate varying levels of  
14 resources, loads, or reserve requirements and to examine the cost impact of each  
15 change.

16 As part of this analysis, PROMOD® also considers physical constraints of  
17 generation and fuel, emissions constraints, and reserve requirements. The software  
18 takes into account the operational advantages and disadvantages of each generation  
19 type and quantifies the cost impact of forcing operation away from the most  
20 economical way in which to operate the system.  
21  
22

1  
2 **Q. WHAT ASSUMPTIONS DID NAVIGANT USE REGARDING THE**  
3 **AMOUNT OF SOLAR GENERATION ON DESC'S SYSTEM?**

4 A. In conducting the Study, Navigant considered two scenarios which represent  
5 two tranches of solar projects. The first tranche of roughly 300 MW of solar  
6 generation does not have a specific variable integration charge clause in their PPAs  
7 while the second tranche of roughly 700 MW does.  
8

9 **Q. WHAT IS THE IMPACT IF MORE SOLAR IS ADDED TO THE DESC**  
10 **SYSTEM THAN IS CONSIDERED IN THE STUDY?**

11 A. As more solar generation is interconnected with the Company's system,  
12 DESC will need to hold an increasing amount of reserves to integrate it. It is  
13 appropriate to incorporate the additional reserves directly into DESC's model used  
14 to calculate avoided cost.  
15

16 **Q. PLEASE DESCRIBE THE IMPACT OF GEOGRAPHIC DIVERSITY OF**  
17 **RENEWABLE RESOURCES AND THE IMPORTANCE OF INCLUDING**  
18 **IT IN THE STUDY.**

19 A. The concept of geographic diversity recognizes that solar generation is not  
20 located in a single area, but in different places throughout a system. Since weather  
21 can vary significantly between locations, even within a relatively compact service

1 territory, geographic diversity means that there is variability in how weather will  
2 affect the generation output of dispersed solar installations at any given time.

3 It is critical to incorporate geographic diversity in an integration cost study  
4 because it has the effect of reducing the total amount of uncertainty facing DESC.  
5 Without considering geographic diversity, the estimated integration costs would be  
6 too high. For this study, geographic diversity was included in all phases of the  
7 analysis including actual data from 8 solar sites on the DESC system.  
8

9 **Q. WHAT LEVELS OF OPERATING RESERVES DID NAVIGANT STUDY**  
10 **FOR EACH OF THE SOLAR PENETRATION SCENARIOS AND WHY?**

11 A. The analysis of solar uncertainty on the DESC system showed that the  
12 forecast error for solar 4 hours before operation is dependent upon the level of solar  
13 generation on the system. Table 2 below shows the relationship between the level  
14 of expected generation and the risk of less generation actually being available at the  
15 time of operation. The main result is that as the expected solar generation (as a  
16 percentage of installed solar nameplate facility rating) increases, the percentage of  
17 that generation which is at risk of not actually being available declines.  
18  
19  
20  
21  
22

*Table 2: Comparison of Expected Generation and Actual Generation*

<b>Expected Generation as % of Installed Solar Nameplate Facility Rating</b>	<b>Maximum Drop in Generation</b>
< 40%	75%
40% - 50%	65%
50% - 55%	45%
> 55%	25%

When committing units, DESC needs to maintain sufficient reserves to be able to increase generation to replace solar generation that does not meet forecasted amounts. Table 3 below shows the level of reserves needed for the maximum daily solar generation in each month in each solar penetration scenario. The business-as-usual (“BAU”) reserves are the reserves currently needed to satisfy VACAR requirements and to safely and reliably serve the load on the Company’s system.

*Table 3: Reserves Needed to Maintain Reliability*

<b>Year</b>	<b>BAU</b>	<b>Initial Solar</b>	<b>All Solar</b>
<b>2020</b>	240	348	529
<b>2021</b>	240	349	579
<b>2022</b>	240	351	581
<b>2023</b>	240	352	582
<b>2024</b>	240	354	584
<b>2025</b>	240	356	586
<b>2026</b>	240	358	588
<b>2027</b>	240	360	590
<b>2028</b>	240	363	593
<b>2029</b>	240	365	595
<b>2030</b>	240	368	598
<b>2031</b>	240	371	601
<b>2032</b>	240	375	605

Because the solar forecast is not the same each day, Navigant then blended the results of the PROMOD® runs with the different levels of reserves to account for days in which less solar is forecasted than others. For example, the analysis calculated integration costs for the All Solar Case using the following proportions of days in which these levels of reserves must be maintained:

- All Solar level of reserves is needed 38% of the days
- Intermediate level of reserves is needed 51% of the days
- Initial Solar level of reserves is needed 12% of the days

1 **Q. WILL UTILITY COSTS INCREASE AS A RESULT OF INTEGRATING**  
2 **SOLAR GENERATION ON AN ELECTRIC SYSTEM?**

3 A. Yes. Solar integration will increase utility costs. For example, a utility's fuel  
4 costs can increase as units are required to operate at less than optimally efficient  
5 levels. Start-up costs also can increase due to the increased need to cycle generating  
6 units on and off more frequently. Variable maintenance costs can increase either  
7 when generating units with higher variable cost are dispatched to provide needed  
8 reserves or due to the additional stress that is placed on units that are ramping to  
9 follow the solar generation. Emissions costs also can increase if the generating units  
10 needed to provide reserves have higher emissions expenses. Finally, a utility's  
11 capital costs can increase if it is required to add new generating resources or if  
12 capital investments are made to increase the flexibility of existing generating units.

13  
14 **Q. DOES THE STUDY CONSIDER SYSTEM COSTS FOR SCENARIOS WITH**  
15 **DIFFERENT LEVELS OF OPERATING RESERVES?**

16 A. Yes. The Study calculates operating reserve levels as the maximum daily  
17 potential forecast error of solar generation at each level of solar penetration. This  
18 maximum was fairly constant by month but varied day-to-day. For days in which  
19 solar generation is forecasted to be low, the level of reserves that the utility needs  
20 to maintain are less than the overall monthly maximum.

21 If the maximum operating reserve increases were assumed to be maintained  
22 every day, the estimate of integration costs would be too high. PROMOD® does

1 not allow operating reserve levels to change day-to-day. Therefore, in order to  
2 incorporate the days with lower requirements, Navigant calculated the costs using  
3 varying levels of operating reserves and then blended those costs using weightings  
4 tied to the proportion of days with the appropriate level of solar uncertainty. This  
5 blending ensures that the study does not overestimate costs.

6  
7 **Q. DOES THE STUDY CONSIDER THE POSSIBILITY OF CHANGING HOW**  
8 **THE COMPANY'S FAIRFIELD PUMPED STORAGE OPERATES IN**  
9 **ORDER TO INTEGRATE SOLAR GENERATION?**

10 A. Yes. The PROMOD® representation of Fairfield Pumped Storage allows the  
11 model to change its operation to minimize overall system cost while meeting the  
12 requirements for solar integration. The pumped storage was allowed to both provide  
13 operating reserves and to smooth out the net load that must be met by DESC  
14 generation. Therefore, the presented variable integration costs are inclusive of the  
15 ability to change Fairfield Pumped Storage's operation.

16  
17 **VARIABLE INTEGRATION COST STUDY CONCLUSIONS**

18 **Q. BASED ON THE STUDY, WHAT IS THE INTEGRATION COST FOR**  
19 **VARIABLE GENERATION ON THE DESC SYSTEM FOR THE SECOND**  
20 **TRANCHE OF SOLAR RESOURCES?**

21 A. The incremental variable integration cost for the incremental solar in the All  
22 Solar Case is \$4.14/MWh. The PR-1 and PR-2 rates previously approved by the

Commission did not include these costs. Table 4 below shows the calculation of the incremental costs.

*Table 4: Variable Integration Costs on DESC's System*

	<b>Initial Solar</b>	<b>All Solar</b>	<b><i>Incremental All solar</i></b>
<b>Cost Difference NPV (2020 \$)</b>	\$21,441,812	\$73,242,219	<b><i>\$51,800,407</i></b>
<b>Solar Generation NPV (MWh)</b>	6,091,424	18,495,510	<b><i>12,504,086</i></b>
<b>Levelized Cost (2020 \$/MWh)</b>	\$3.52	\$3.96	<b><i>\$4.14</i></b>

**Q. DOES THE SYSTEM COST CHANGE AS ADDITIONAL RESERVES ARE MAINTAINED?**

A. Yes. In every solar penetration case, when more reserves are required on the system, the system cost and the levelized variable integration costs increase.

**Q. IS IT POSSIBLE FOR DESC TO REDUCE ITS COSTS TO INTEGRATE VARIABLE GENERATION BY ADDING BATTERY STORAGE OR NEW COMBUSTION TURBINE ("CT") GAS UNITS SOLELY TO PROVIDE RESERVES?**

A. At this time, adding additional resources solely to provide reserves is not a cost-effective approach to lower the variable integration costs of the current and expected solar generation. The amount of 1-hour battery storage that can be added for the additional system costs of approximately \$73.2 million is approximately 95 MW assuming future improvements in technology and cost declines through 2025. The amount of CT gas capacity that can be added is approximately 110 MW.

1 Neither of these capacities is sufficient to provide the reserves needed to integrate  
2 the solar generation.

3  
4 **Q. IS IT POSSIBLE FOR SOLAR PROJECTS TO INTERCONNECT TO THE**  
5 **DESC SYSTEM WITHOUT INCREASING RESERVE REQUIREMENTS?**

6 A. Yes, while the detailed conditions need to be defined in the future, broadly  
7 the following describe the conditions in which DESC would not need to increase  
8 reserve requirements in order to plan for potential drops in solar generation.

- 9 • DESC has some ability to control the dispatch of the generation from the  
10 project.
- 11 • Be able to replace enough of the nameplate capacity of the project when  
12 called upon to make up for generation lower than forecasted.
- 13 • Be able to maintain the replaced generation for sufficient time to avoid  
14 reliability challenges.

15 Example projects that might be able to meet these conditions include solar  
16 projects with co-located storage or solar that is configured to be operated flexibly.

17  
18 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

19 A. Yes.



## Matthew Tanner, PhD

### Director

matthew.tanner@navigant.com

Washington, DC

Direct: 202 973-2439

### Professional Summary

Matt is a director in Navigant's Energy and Capital Markets group. He supports market participants in understanding and planning for the changing dynamics of energy markets and the overall power industry. With over 10 years' experience in integrated resource planning, energy market strategy, and risk analysis, he focuses on developing and providing highly analytical and creative approaches for utilities, investors, independent power producers, and other market participants to evaluate emerging market opportunities and adapt their business models to the changing markets across North America.

Matt is an expert in helping clients understand the underlying drivers of Navigant's wholesale market forecasts as well as potential changes that can drive risk both on the upside and downside. For utility clients, Matt ensures that they understand their changing requirements and technology options to meet those requires. He supports them in ensuring that they can operate their systems reliably and at the lowest cost.

### Areas of Expertise

- **Utility Strategy and Resource Planning.** Guides utilities throughout North America in their resource planning and developing their strategy in response to the changing power system. Specializes in developing novel approaches for utilities to evaluate emerging issues such as integration of variable energy resources, the economics of decarbonization, and business opportunities with new technologies and distributed energy resources.
- **Wholesale Market Forecasting and Business Strategy.** Leads and contributes to a wide variety of energy planning projects both at the wholesale and distribution level. Focuses on scenario analysis of asset value, wholesale power market price forecasting, benefit/cost analysis, and asset decision analysis for existing and emerging technologies. Has strong experience evaluating and developing business models for battery and bulk storage stacking applications in energy, ancillary services, and capacity.
- **Wholesale Market Design and Participation.** Strategic support of ISOs and system operators as they are developing, reforming, or determining whether to join organized energy markets. Works on the key challenges and opportunities that are arising due to zero marginal cost generation and the rising need and value of flexibility in the system.



## Matthew Tanner, PhD

Director

### Select Relevant Experience

#### Utility Strategy and Resource Planning

- Transmission and Generation Strategy Support, LADWP 2018 – present. Leading the economic analysis of LADWP's strategy for operating its system and considering options as renewable penetration increases.
- Variable Integration Charge Analysis, SCEG, 2018- 2019. Led the analysis of the renewable uncertainty and variable integration charge. Testified on the results.
- Renewable Integration Study, Chelan PUC, 2019. Led the subhourly analysis of the operations impact of a large solar facility on the system operation and NERC standards.
- Retail Choice Impact Analysis, Confidential, 2019. Led the economic analysis of the impact of retail choice on utilities in a state.
- Once-Through-Cooling Retirement Analysis, LADWP, 2017 - 2018. Leading the economic analysis of LADWP's strategy regarding retirement of its once-through-cooling units.
- IRP Support, FortisBC, 2016-2018. Supported FortisBC as an expert in IRP modelling and the Northwest US power market.
- Variable Generation Study, NorthWestern, 2017 – 2018. Led project to estimate increased needs for renewable integration support for NorthWestern with rising wind and solar penetration.
- IRP Support, SaskPower, 2016. Supporting SaskPower in redesigning its planning process including definitions of scenarios, resource options, and risk analysis.
- Development of Short-Term Asset Risk Model, J-Power, 2016. Led the effort and designed a short-term market forecasting model to support J-Power in understanding upcoming market risks.
- Monte-Carlo Analysis of Transmission Project Costs, Exelon, 2016. Developed a Monte-Carlo model that supported the response to an RFP by providing a simulated range of costs for a transmission project.
- Review of Resource Plan, Austin Energy, 2015. Project manager to review Austin Energy's resource plan and presented results to city council.
- Renewable Integration Analysis, LADWP, 2015. Task lead to evaluate the ability of LADWP to integrate high levels of renewable power into its system from a production cost planning framework.
- Evaluation of Best Practices Incorporating Distributed Energy Resources (DER) into IRP, DTE, 2015. Led project to survey utilities on best practices in incorporating DER and wrote report.



## Matthew Tanner, PhD

Director

- Integrated Resource Planning Model, Northwest Power and Conservation Council, 2014-2015. Helped redevelop the RPM integrated resource planning model that the council uses in the Northwest.
- Developed Simulation of Power Plant Outages and Penalties Under Contract, TransCanada, 2015. Developed a Monte-Carlo simulation of unit outages and the implications for penalties under the plant PPA to support contract negotiations.

### Wholesale Market Forecasting and Business Strategy

- California Behind-the-Meter Storage Analysis, 2018 – 2019. Led market due diligence for a potential transaction of the owner of a fleet of behind-the-meter storage assets in California.
- Retainer Support, Kruger Energy, 2018 – present. Supported Kruger in understanding on-going market dynamics in the Northeast.
- Evaluation of Microgrid, Texas Microgrid, 2018 – 2019. Forecasted ERCOT market value for behind-the-meter microgrid in ERCOT.
- Evaluation of storage portfolio value, STEM, 2019. Forecasted market participation and value for a portfolio of storage assets in ISONE.
- Storage project operations analysis, Able Grid, 2019. Led analysis of the potential operations and revenue for a storage project located in ERCOT.
- Evaluation of Portfolio of Renewable Assets, John Hancock, 2018. Led the market forecasting for a portfolio of renewable assets including basis and congestion risk.
- Post-PPA Valuation of Assets in Ontario and Quebec, Enbridge, 2018. Led the estimation and valuation of renewable assets in Ontario and Quebec that are coming off of PPAs in the next 15 years.
- Economic Analysis of SOO Green Renewable Rail Project, SOO Green, 2017. Led the arbitrage analysis of a potential high voltage direct current transmission line from Iowa to Illinois.
- Economic Analysis of PJM Battery Project, SGEM, 2017. Led the forecasting regulation prices and valuation of a battery project in PJM.
- Economic Analysis of San Vicente Pumped Storage, San Diego Water Authority, 2016. For SDWA, led the modelling task to evaluate the economics of the pumped storage facility within the California ISO (CAISO) market.
- Ancillary Service Market Dynamics and Price Forecasting, E.ON, 2016. For E.ON. led project to develop a report explain A/S market prices and the key drivers.



## Matthew Tanner, PhD

Director

- Pennsylvania-New Jersey-Maryland Interconnection (PJM) Hydro Transaction, PSP, 2015. Forecasted market value for a hydro asset and advised on market rules and changes in PJM to support a potential transaction.
- Renewable Power Transactions, Korean Electric Power (KEPCO), 2015. Supported KEPCO in valuating renewable plants in US and advised on impacts of market drivers and regulatory changes.
- Modelling of New York ISO (NYISO) Frequency Market Drivers, US Department of Energy, 2015. Reviewed and modelling the key market drivers for the NYISO frequency regulation to forecast prices.
- Analysis of Value of Fast Dispatch in Electric Reliability Council of Texas (ERCOT), Investor, 2015. Modelled dispatch of a fast-start resource in ERCOT operating in real-time market.

### Wholesale Market Design and Participation

- Strategic Support of Market Renewal, Independent Electricity System Operator (IESO), 2017-2018. Project manager for Navigant's strategic supporting role for IESO's market renewal effort. Helping stakeholders understand cross-cutting issues and the needs of the changing power system.
- Market Renewal Workshops, IESO, 2016-2017. Created and presented a set of workshops to internal and external stakeholders to educate on market renewal.
- Analysis of Economic Impacts of RTO Membership, LADWP, 2016. Led economic analysis task to support LADWP to understand the impacts of potential RTO membership.
- Evaluation of Joint Economic Dispatch in Florida, 2016. Led the economic modelling of joint economic dispatch within the FRCC territory.
- Calculation of Default Emissions Factor, Ontario Ministry of Energy, 2016 - 2017. Modelled the marginal resources for markets exporting to Ontario and calculated the emissions factors that should be applied to be consistent with Ontario carbon policy.

### Work History

Director, Navigant Consulting, Inc.  
Operations Research Analyst, US Information Administration

### Education

PhD, Industrial Engineering  
BSE, Operations Research and Financial Engineering

Texas A&M University  
Princeton University



## Cost of Variable Integration

# Cost of Variable Integration

Prepared for Dominion Energy South Carolina



**Submitted by:**

Navigant Consulting, Inc.  
1200 19th Street, NW  
Suite 700  
Washington, DC 20036

202.973.2400  
navigant.com

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## Cost of Variable Integration

### TABLE OF CONTENTS

<b>Disclaimer .....</b>	<b>iii</b>
<b>Executive Summary .....</b>	<b>iv</b>
Study Approach .....	iv
Renewable Uncertainty and Need for Additional Reserves .....	v
Conclusions .....	vi
<b>1. Impact of Solar on DESC Operation .....</b>	<b>8</b>
1.1 The DESC Power System .....	8
1.2 Changes to System Operation with Solar .....	9
<b>2. Study Methodology .....</b>	<b>14</b>
2.1 Key Study Assumptions .....	14
2.1.1 System Load .....	14
2.1.2 DESC Generating Resources .....	15
2.1.3 Solar Penetration on the DESC System .....	16
2.2 Modeling the DESC System with PROMOD .....	17
2.3 Forecasting Requirements to Integrate Solar .....	18
2.4 Estimating Integration Costs .....	19
<b>3. Solar Generation Variability in DESC Service Territory .....</b>	<b>20</b>
3.1 Data Sources .....	20
3.2 Detailed Approach .....	21
3.3 Solar Generation Variability Results .....	21
3.4 Geographic Diversity .....	23
<b>4. Demonstrating the Need for Additional Reserves .....</b>	<b>24</b>
4.1 Reliability Challenges without Adding Reserves for Variable Integration .....	24
4.2 Calculating the Additional Reserve Requirements .....	25
4.3 Reserve Requirements for Additional Solar .....	Error! Bookmark not defined.
<b>5. Mitigation Options and Integration Costs .....</b>	<b>28</b>
5.1 Potential Mitigation Options .....	28
5.2 System Impacts of Holding Additional Reserves .....	28
5.3 Cost of Holding Additional Reserves without Other Changes .....	29
5.4 Alternative Variable Generation Integration Approaches .....	30
5.4.1 DESC adds Resources .....	30
5.4.2 Solar Projects add Storage or Operate Flexibly .....	31
<b>Appendix A. Market Modeling Process .....</b>	<b>A-1</b>
A.1 Electric Market Simulation .....	A-1



## Cost of Variable Integration

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## Cost of Variable Integration

### EXECUTIVE SUMMARY

This study was commissioned by Dominion Energy South Carolina (DESC) in order to estimate the impact solar installations will have on system operations and the resulting incremental costs. The study considers the variable integration requirements for solar generation that is currently contracted. Due to the variable nature of solar generation, DESC needs to ensure that there are sufficient reserves on the system to be able to meet load when less solar is generated than was forecasted. This study evaluates the uncertainty in the solar generation, the resulting reserve requirement for DESC, and the added operating costs from holding those reserves for solar that is currently contracted. The study also discusses alternative mitigation options and configurations of solar projects, with or without storage, that would avoid the need for DESC to hold additional reserves.

DESC's challenge is that the utility combines a large proportion of inflexible baseload (coal and nuclear) generation with a high penetration of solar installations. This causes operational challenges due to the limits of the baseload generation for ramping up or ramping down in response to solar generation.

### Study Approach

For this analysis, Navigant first benchmarked its PROMOD IV (PROMOD) model to DESC's system to create a baseline. Two solar penetration scenarios were then run to analyze the impacts that various levels of solar would have on the system. The two scenarios represent the first tranche of solar resources that connected to the system that do not have a variable integration charge component to their contract and the second tranche of solar that does have the variable integration charge component in their contracts.

- Initial Solar Case – 336 MW of solar generation interconnected with DESC's system by 2020.
- All Solar Case – 1,044 MW of solar generation interconnected with DESC's system by 2020.

Further installations of solar on the DESC system will need to have their specific avoided costs calculated including variable integration requirements.

The following methodology was used to evaluate the impacts of solar generation and the variable integration costs:

1. The PROMOD production cost software was benchmarked to the existing DESC system to provide a baseline of system operation in each of the solar penetration scenarios.
2. Solar generation uncertainty and forecast error was estimated.
3. The additional reserves needed to integrate the solar generation was calculated.
4. PROMOD was used to calculate the increase in production costs due to the additional reserves required and the results were used to determine the levelized variable integration costs.
5. Alternative mitigation options were evaluated.

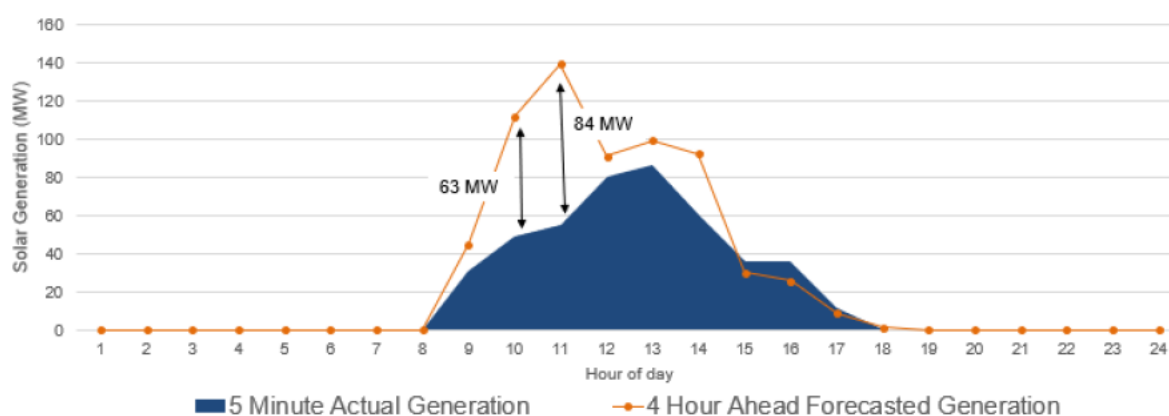


## Cost of Variable Integration

### Renewable Uncertainty and Need for Additional Reserves

DESC must operate the system differently in order to maintain reliability when solar generation increases. The following figure gives an example of how solar forecast error and uncertainty can cause actual generation to be less than forecasted generation. In this case, DESC must have the capability to ramp generation up to meet load when the solar generation is less than expected.

Figure 1. Solar Generation Variability Example



The following table shows the results of the analysis of the maximum expected drop in solar generation as it relates to the level of expected generation.

Table 1. Solar Forecast Uncertainty

Expected Generation as % of Installed Capacity	Maximum Drop in Generation
< 40%	75%
40% - 50%	65%
50% - 55%	45%
> 55%	25%

The mechanism to ensure that DESC can meet load when solar generates less than forecast is to hold additional operating reserves with units that can either start up quickly or are operating at less than full



## Cost of Variable Integration

load. The following table shows the operating reserves that DESC holds now (BAU) and would have to hold in both solar cases.

**Table 2. Maximum Additional Reserves Needed**

Year	BAU	Initial Solar	All Solar
2020	240	348	529
2021	240	349	579
2022	240	351	581
2023	240	352	582
2024	240	354	584
2025	240	356	586
2026	240	358	588
2027	240	360	590
2028	240	363	593
2029	240	365	595
2030	240	368	598
2031	240	371	601
2032	240	375	605

## Conclusions

There are two broad mechanisms for DESC to ensure that there are sufficient reserves on the system:

1. Change operations on the existing system so that there are more operating reserves.
2. Procure quick-start resources such as battery storage or CT gas units that will be able to provide reserves even when offline<sup>1</sup>.

Holding reserves increases costs by causing less efficient units to operate more and by having units operate at less than full capacity, below their most efficient operating points. This increases variable operating and maintenance, fuel costs, emissions costs, and start-up costs. The following table shows how the overall production costs change for DESC in each case and how this leads to an incremental levelized variable integration cost of \$4.14/MWh for the solar projects that are part of the second tranche of installations in the All Solar Case.

<sup>1</sup> Note that there are methods for solar units to provide flexibility and ramping to the system. Although this may be a feasible alternative in the future, this possibility has not been considered in this analysis because DESC cannot implement it unilaterally but only with technological changes by the solar facility owners.



## Cost of Variable Integration

**Table 3. Cost of Holding Additional Reserves**

	Initial Solar	All Solar	<i>Incremental All solar</i>
<b>Cost Difference NPV (2020 \$)</b>	\$21,441,812	\$73,242,219	<b>\$51,800,407</b>
<b>Solar Generation NPV (MWh)</b>	6,091,424	18,495,510	<b>12,504,086</b>
<b>Levelized Cost (2020 \$/MWh)</b>	\$3.52	\$3.96	<b>\$4.14</b>

It does not currently seem cost-effective for DESC to add resources solely to provide the needed reserves. However, it is an option for solar projects to provide that flexibility themselves. There are several ways by which a solar project can operate with sufficient flexibility so that DESC does not need to add reserves. If the project does this, then it is appropriate for DESC to calculate the avoided cost for that specific project without adding any additional reserve requirements. The key issue is that the avoided costs will be different for a project that can operate flexibly vs. a traditional solar installation without the ability to operate flexibly.

The following are some broad conditions for a solar or solar + battery project to avoid an increase in reserves being held by DESC<sup>2</sup>:

- DESC has some ability to control the dispatch of the generation from the project.
- Be able to replace enough of the nameplate capacity of the project when called upon to make up for generation lower than forecasted.
- Be able to maintain the replaced generation for sufficient time to avoid reliability challenges.

Co-locating an appropriately sized battery with the storage project is one possibility for meeting these requirements. Another option is “flexible solar” which is an operating mode in which the solar project generates below its maximum value and can thereby be dispatched up and down by the system.

It is appropriate and necessary for DESC to work with solar project owners to determine options for ensuring that the requirements can be met

<sup>2</sup> The detailed contractual conditions will need to be defined later.



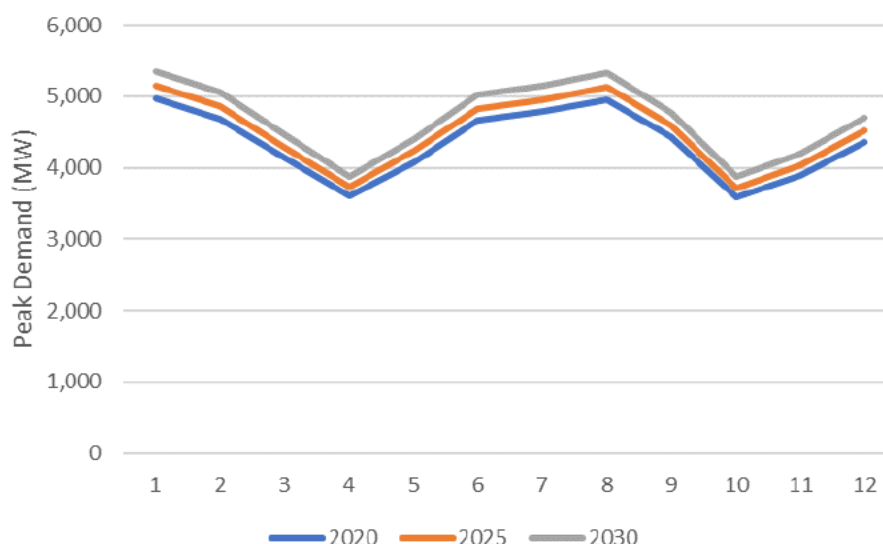
## Cost of Variable Integration

### 1. IMPACT OF SOLAR ON DESC OPERATION

#### 1.1 The DESC Power System

DESC provides electric services for a large portion of South Carolina, with hourly demand typically ranging between 2,000MW and 5,000 MW, and monthly peak demand typically between 3,500MW and 5,500MW. DESC experiences both winter and summer peaks, as shown in Figure 2, with the highest demand occurring during January and August. This trend is expected to remain consistent over time.

Figure 2. Monthly DESC Peak Demand



DESC operators must ensure that both system load and operating reserves are met in all normal conditions. DESC is required to hold 200 MW of reserves at all times to meet their requirements within VACAR to be able to respond to the loss of the single-largest unit on the system<sup>3</sup>. An additional 40MW of reserves are held for load-following. Due to the need for self-sufficiency, DESC must rely on its own generators to meet generation and reserves, and cannot rely on external sources.

Reserve requirements are met by operating the system in a manner to maintain the capability to increase generation quickly up to the level of reserves that are required. For example, many of DESC's combustion turbine (CT) units are able to start within 15 minutes. These units provide reserves even when they are not operating. The combined cycle (CC) units require two hours or more to start if they are

<sup>3</sup> VACAR is a reserve sharing agreement that DESC is a part of. Being part of VACAR helps DESC maintain sufficient contingency reserves in order to respond to the single largest contingency on the system without having to hold all of the reserve requirement. The 200 MW of reserves for DESC is its share of these contingency reserves.



## Cost of Variable Integration

not operating. These units can only provide reserves if they are turned on and operating below their full capability (holding some capability in reserve). It is less efficient, both economically and environmentally, to operate units below full capacity.

A summary of DESC's non-solar resources can be found in the table below; solar is not included as new resources are still being considered and would vary case to case for the scenarios run. DESC also has 100 MW of interruptible load that can be used to meet reserve requirements.

**Table 4. Summary of DESC Resources**

Technology	Name Plate Capacity (MW)	Avg. Ramp Rate (MW/hr)	Quick Start	Avg. Start Cost (\$)
<b>Combined Cycle</b>	2,430	302	No	\$17,101
<b>CT Gas</b>	389	76	Yes <sup>1</sup>	\$0
<b>ST Gas<sup>2</sup></b>	796	186	No	\$3,466
<b>ST Coal<sup>2</sup></b>	1,881	62	No	\$10,317
<b>Nuclear</b>	650	480	No	\$0
<b>Hydro</b>	239	239	No	\$0
<b>Pumped Storage</b>	576	576	No	\$0

1. Urqhart CT Gas #4 is not capable of providing quick start reserves.
2. The Cope Steam Turbine plant runs on natural gas during the summer and on coal during winter, due to fuel availability.

Compared to other power systems such as those in Florida or Duke Energy Carolinas, DESC has a high proportion of "baseload" generating capability from nuclear and coal plants. The key characteristic of baseload plants is that they have limited ability to change their generation quickly and are unable to start-up or shut-down without a long lead-time.

## 1.2 Changes to System Operation with Solar

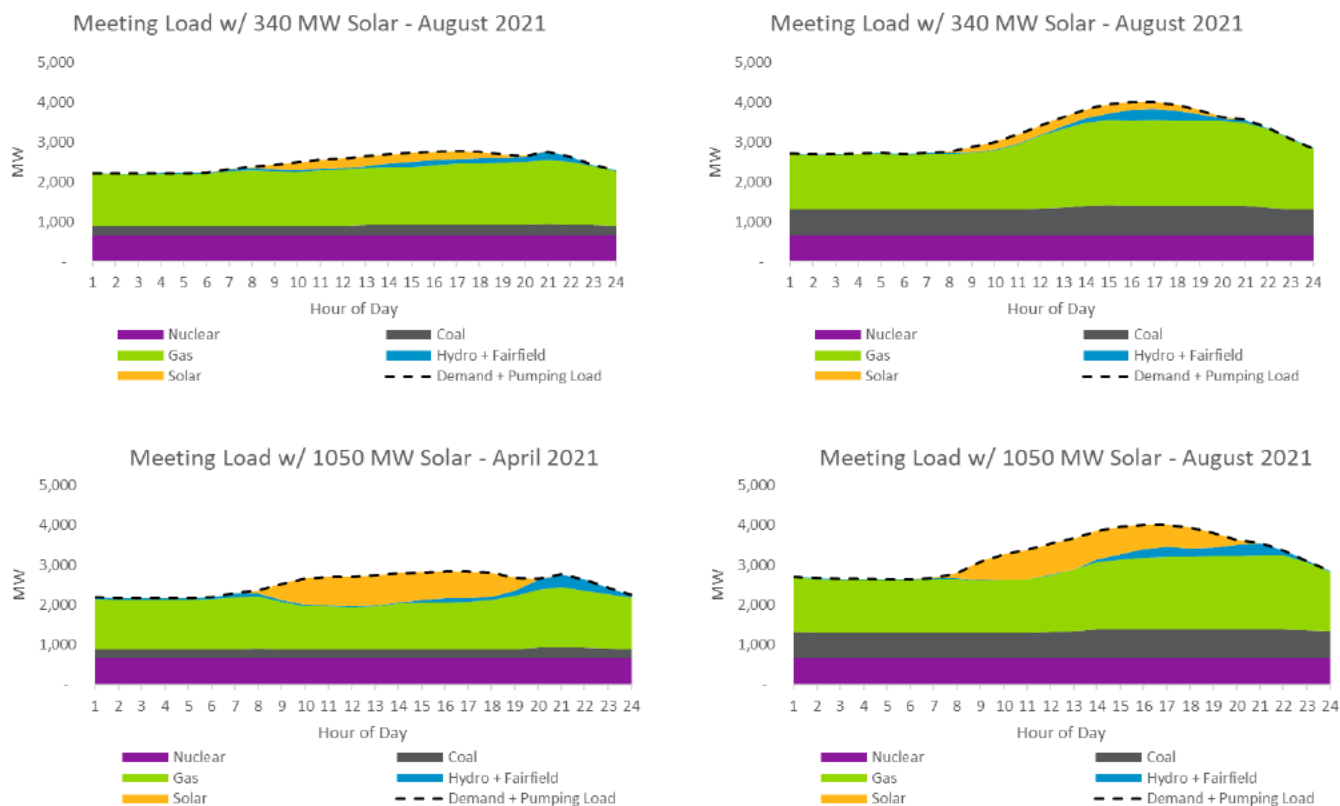
As the amount of solar on the DESC system increases, the existing generators operations will change to ensure that load can be met and reliability criteria can be maintained. Power from solar generation rises in the morning, is at its peak throughout the day, and decreases when the sun sets. Furthermore, solar generation is intermittent meaning that solar generation is not fully controllable by DESC and can be either higher or lower than forecasted. To operate the system, other generators will need to be turned down in the middle of the day when solar generation is highest and sufficient reserves will need to be held so that DESC can maintain operation if solar generation is less than expected.

Some examples of how daily operation changes by season and as solar generation on the system increases are shown in Figure 2.



## Cost of Variable Integration

**Figure 3. Average Daily Operation with Varying Solar Penetration**



Adding solar to DESC's system generally reduces the marginal cost of generating power as solar has no fuel costs associated with generation and adding it allows the DESC system operators to reduce the generation of other units. These direct impacts are calculated in the PR1 and PR2 avoided cost filings and show the benefits from solar to reduce fuel use and other operating costs.

However, DESC must also ensure that sufficient system reserves are available to replace generation when the actual solar generation is below the forecast. This would result in holding additional reserves on top of the 240 MW already required; DESC would have to change their system operation to ensure that these reserves can be met.

Depending on how the system is operating, there are several potential outcomes for DESC operation:

- There may already be sufficient online flexibility to meet the additional reserves in which case there would be no change to the operation.
- It may be necessary to generate more from less efficient resources to ensure that other units that can provide ramping capabilities are at less than full capacity.
- It may be necessary to start-up less efficient generation in order to be able to provide the reserves.



## Cost of Variable Integration

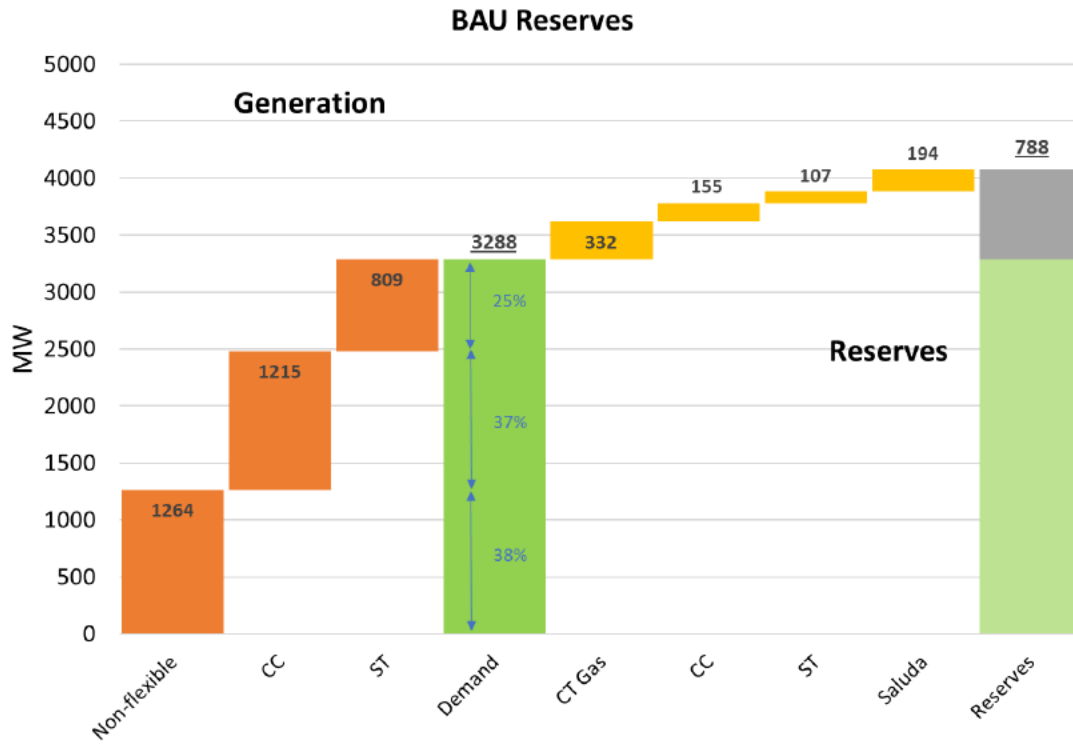
The costs to ensure this flexibility are estimated in this study and are separate from the system costs calculated in the PR1 and PR2 avoided cost filings.

The following two examples shows how system operation can change when additional reserves are required. With the current amount of reserves that DESC holds, the lowest cost way to operate the system is to have the CC fleet of units generate at almost full capacity while providing few reserves. Most of the system reserves are provided by Saluda and the CT gas units. When additional reserves are needed, the operators must turn down the CC units to provide reserves and turn up Steam Turbine (ST) Coal units to provide energy. This increases the cost to operate the system.



Cost of Variable Integration

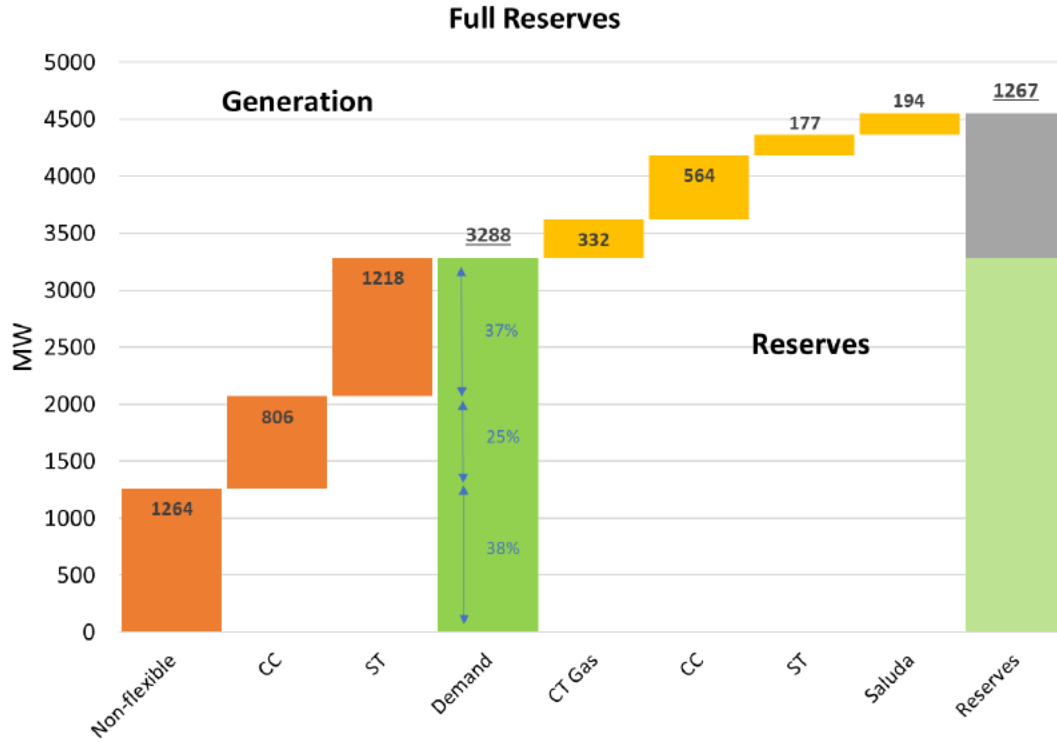
Figure 4. DESC Operation with Business-as-Usual Reserves Required





Cost of Variable Integration

Figure 5. DESC Operation with Additional Reserves





## 2. STUDY METHODOLOGY

As discussed in Section 1, operating DESC's system with increasing solar installations will require the utility operators to maintain sufficient operating reserves and ensure that load can be served even when actual solar generation is less than expected generation. Mechanically, this means that DESC operators will need to maintain sufficient operating reserves (the ability to ramp units up) to both meet VACAR requirements and to cover any unexpected shortfall of solar generation.

The general approach to calculate the costs of this additional requirement is to simulate system operation with and without the additional operating reserves, compare system costs in the two scenarios, and evaluate if there are any other potential mitigation alternatives that could result in lowered system costs. The study forecasts system integration costs for 15 years from 2020 -2034. The following describes the full study methodology and assumptions in detail.

### 2.1 Key Study Assumptions

As a baseline, this study uses the same assumptions as DESC's Integrated Resource Plan (IRP). The key assumptions of the IRP include the forecasted system load and the existing and new resources needed to meet this load requirement.

#### 2.1.1 System Load

The following chart shows the forecasted annual system peak load<sup>4</sup> for the study period of 2019 to 2032. Annual load grows at a constant and relatively low rate, with a CAGR of approximately 0.8% over the study period.

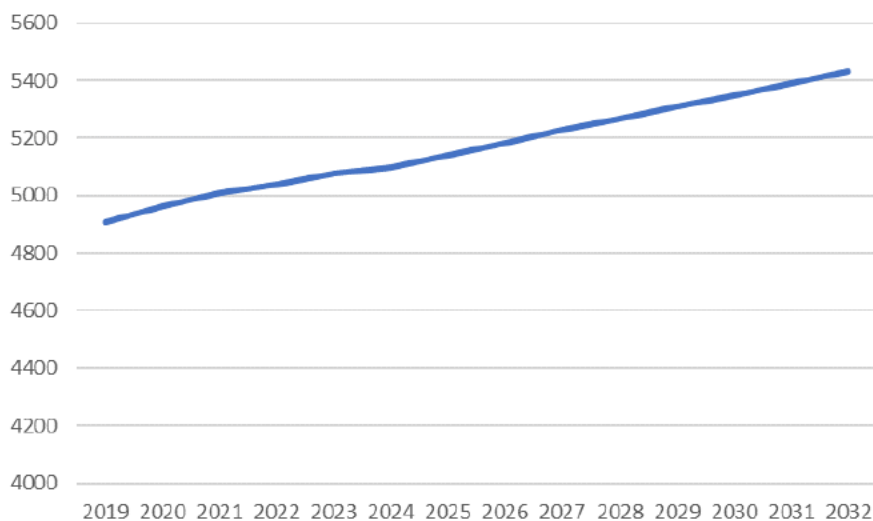
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<sup>4</sup> The system was simulated hourly and the forecasted load is used on an hourly basis.



## Cost of Variable Integration

**Figure 6. Annual DESC Peak Demand**



### 2.1.2 DESC Generating Resources

Below is the list of DESC units. Solar units are not included as they vary between the cases analyzed by Navigant. The combined-cycles, ST Coal, ST Gas, and V.C. Summer nuclear plant provide the majority of baseload generation needed in DESC, with the ST Gas and CCs able to ramp up their output during peak hours. The CT Gas, Fairfield, and Saluda plants are used for reserves and peaking needs.



## Cost of Variable Integration

**Table 5. DESC Dispatchable Units**

Plant	Units	Technology	Name Plate Capacity (MW)	Ramp Rate (MW/hr)	Quick Start	EFOR (%)	Start Cost (\$)
Columbia Energy Center	1	CC	540	540	No	1.67	\$17,534
Jasper	1	CC	920	190	No	2.4	\$26,301
Urquhart CC	1 & 2	CC	450	450	No	0.9	\$17,534
DESC Unnamed CC (2029 onward)	1	CC	520	127	No	2.4	\$0
Coit	1 & 2	CT Gas	26	26	Yes	5	\$0
Hagood	4	CT Gas	99	99	No	2	\$0
Hagood	5 & 6	CT Gas	42	42	Yes	5	\$0
Parr	1 & 3	CT Gas	73	73	Yes	5	\$0
Urquhart CT	1 - 4	CT Gas	97	97	Yes	5	\$0
Williams	1 & 2	CT Gas	52	52	Yes	5	\$0
V.C. Summer	1	Nuclear	650	480	No	2	\$0
Fairfield	1	Pumped Hydro	576	576	Yes	0	\$0
Wateree	1 & 2	ST Coal	780	0	No	3.6	\$15,286
Williams	1	ST Coal	615	0	No	4.3	\$8,772
Cope	1	ST Coal	486	240	No	2	\$4,299
Cope	1	ST Gas	420	240	No	1.1	\$4,299
McMeekin	1 & 2	ST Gas	272	150	No	1	\$2,923
Urquhart ST	3	ST Gas	104	60	No	12.2	\$1,522
Saluda	5	Hydro	194	194	Yes	0	\$0
Other Hydro Units*	-	Hydro	45	45	Yes	0	\$0

*Note: Hydro units are Neal Shoals, Parr Hydro, Saluda Hydro, and Steven's Creek*

### 2.1.3 Solar Penetration on the DESC System

There are slightly more than 1,000 MW of solar projects that have contracts with DESC. Of these, roughly 700 MW have clauses in their contracts that includes a variable integration charge. The rest of the solar generation does not have this clause. To evaluate the appropriate variable integration charge Navigant ran two scenarios that are used to show the impact that the first ~300 MW of solar have on the system and on system costs and then the impact the next ~700 MW have on the system<sup>5</sup>.

- Initial Solar Case – 336 MW of solar generation interconnected with DESC's system.
- All Solar Case – 1,044 MW of solar generation interconnected with DESC's system.

<sup>5</sup> Future solar installations will not have a variable integration charge and instead the reserve requirements due to those projects will be incorporated directly into the avoided costs.



## Cost of Variable Integration

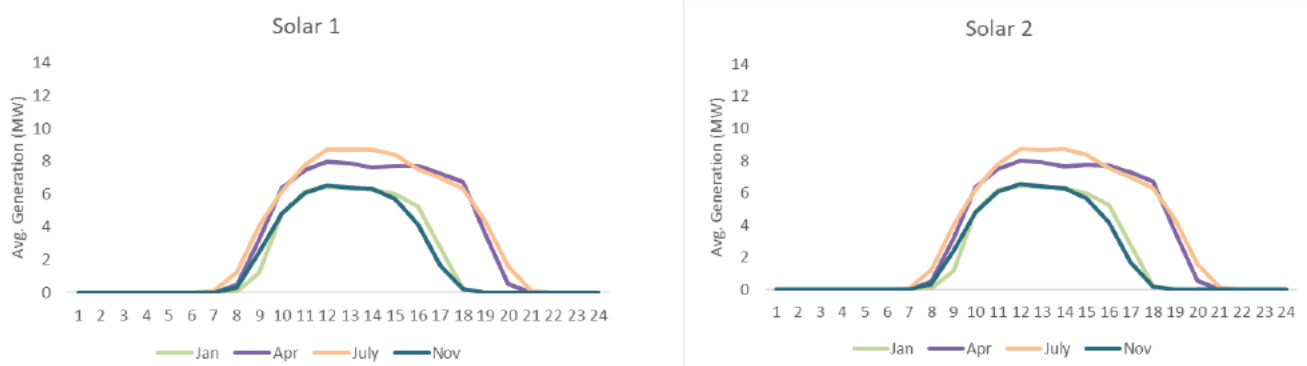
The maximum solar capacity for both cases by year is shown in Table 6.

**Table 6. Maximum DESC Solar Capacity**

Solar	Maximum Capacity (MW)			
	2020	2021	2025	2030
Initial Solar Case	336	340	363	404
All Solar Case	1,044	1,048	1,071	1,112

Navigant models all generation on an hourly basis; solar is modeled in PROMOD using a fixed 8760 hourly shape for generation. The 8760-shapes were based on historical hourly generation data provided by DESC. Figure 7 shows typical daily generation for two typical DESC solar plants,

**Figure 7. Example Daily Solar Generation**



## 2.2 Modeling the DESC System with PROMOD

Production cost models are a class of models that are used to complete analyses of electricity system costs. These models are appropriate for evaluating how system costs change when aspects of those systems change.

For this study, PROMOD was used. PROMOD is a widely licensed Production Cost Model used by many utilities and ISOs including PJM and MISO. There are other available Production Cost Models and consistent results can be expected if a different model was used for the study.

Like all production cost models, PROMOD simulates system operation hourly to minimize the total operating cost while ensuring that generation and load are matched and that operating reserve requirements are met. The model also takes into account generator operating limits and transmission



## Cost of Variable Integration

constraints. The key outputs of the system simulation are the hourly details of system operation including generation by unit and the hourly operating costs.

From PROMOD, the production costs can be calculated by summing:

- Fuel costs
- Variable operating costs
- Start-up costs
- Emissions costs

In this study, DESC is modeled as a mostly isolated system without dynamic transmission connections to surrounding systems. This is appropriate for a planning study as it captures the requirement for DESC to maintain self-sufficiency in planning. As DESC does have the ability to contract for external power, emergency power imports were allowed at a cost of \$300/MWh.

### 2.3 Forecasting Requirements to Integrate Solar

The necessary additional operating reserves that are needed with solar on the system are estimated using data sets providing by the National Renewable Energy Lab (NREL) specifically for solar integration studies<sup>6</sup>. These data sets provide forecasted and real-time solar generation data at sites across South Carolina. In the future, as DESC gains experience operating with solar generation, the solar uncertainty analysis can be updated with actual operating data rather than the data provided by NREL.

The operating reserve requirements from solar are driven by the level of forecast uncertainty in solar generation. The NREL dataset provides the 4 hour-ahead forecast of hourly solar generation. This is the forecast that DESC system operators would use to schedule their units and determine which generators are required to be line. The forecasted solar is compared to the real-time solar generation dataset to calculate the generation variance from the forecast. DESC needs to hold sufficient reserves to be able to respond to the worst-case downward variance of solar generation while maintaining their reserve requirements.

An outcome of the solar uncertainty analysis, described in more detail in Section 3, is that the level of solar generation uncertainty depends on the total level of solar generation. The amount of reserves that need to be held by DESC for variable integration depend on the level of forecasted solar generation. This dynamic is incorporated into the study analysis by blending the production costs of several cases operating the system with different levels of operating reserves to account for the day-to-day variability in the overall requirements.

<sup>6</sup> <https://www.nrel.gov/grid/solar-integration-data.html>



## Cost of Variable Integration

### 2.4 Estimating Integration Costs

To calculate the integration costs of the various mitigation options, PROMOD was ran with different levels of operating reserves calculated as a mitigation option and the production costs were compared to the “Business as Usual” (BAU) scenario, which is the PROMOD scenario benchmarked to recent DESC system operation prior to the addition of much of the solar.

The study includes a comparison of the system costs as operating reserves increase to handle solar uncertainty. These costs are compared for both of the solar penetration scenarios and up to three different levels of operating reserves. Table 7 shows the full set of study scenarios. The BAU reserves are the 240MW currently required. The other reserve levels are those required for the uncertainty associated with the varying levels of solar penetration.

**Table 7. Solar and Reserve Scenarios**

Initial Solar (~350 MW)	All Solar (~1050 MW)
BAU Reserves	BAU Reserves
Initial Solar Reserves	Initial Solar Reserves
	All Solar Reserves

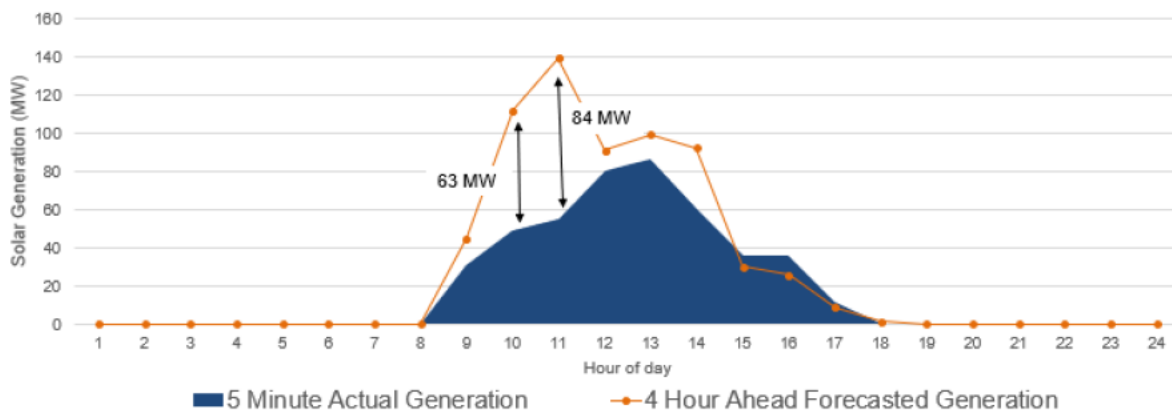
Beyond simply holding additional reserves with the current power system, DESC has the ability to add new resources such as CT gas or storage that can provide reserves. If new units are added as a mitigation option, then new resources are added to the set that is available to DESC to meet load and reserve requirements. The capital costs of the new resources would be added to the total mitigation costs for comparing between the BAU and change scenarios. The study tests whether additional resources can be used to reduce the total integration costs.



### 3. SOLAR GENERATION VARIABILITY IN DESC SERVICE TERRITORY

Solar generation is intermittent, its actual operation cannot be perfectly forecasted and there is nearly continuous variation in generation that must be reacted to by DESC operators. The following chart shows the difference between a 4-hour ahead forecast and actual 5-minute operation of solar in South Carolina. The forecasted generation varies by as much as 84 MW for a single hour which could be an issue in maintaining system reliability for DESC and would require adequate reserves that can be called upon to maintain supply and demand balance in the region. The chart below captures total solar generation at four different locations in the system to provide a system-wide variability whereas variability at a single solar site can be much higher in terms of percentage of solar generation shortfall.

Figure 8. Solar Generation Variability Example



#### 3.1 Data Sources

The amount of solar variability that DESC operators will need to be able to respond to is driven by the level of forecast uncertainty for solar generation in the territory. The challenge is that there is a very short track record in the system for how much solar uncertainty there is. DESC does not have data that can be used to calculate the distribution of the difference between solar generation forecasts and the actual solar generation.

To be able to complete the study, Navigant used two sources of solar data:

- The hourly shape for solar generation that is inputted into PROMOD is developed from an aggregation of real solar generation hourly shapes from DESC.



## Cost of Variable Integration

- The forecast uncertainty is developed from the National Renewable Energy Lab's (NREL) Solar Integration Dataset<sup>7</sup>. This is a public dataset that provides both forecasted and real-time solar generation at a large number of sites across the U.S.

### 3.2 Detailed Approach

The solar forecast error is calculated as the difference between the 4-hour ahead forecast generation and the 5-minute actual solar generation. This is appropriate because as the solar generation changes in the period between the 4-hour ahead forecast and actual operation, DESC will not have sufficient time to turn on any additional CC or ST units. The only reserves that are available are the additional generating capacity, or headroom, for Fairfield, Saluda, the CTs, and the CCs and STs that may already be online.

The following methodology is used to calculate the solar forecast error.

1. Calculate the 4-hour ahead solar forecast as the average of 4 potential solar sites located around the DESC service territory.
2. Calculate the 5-minute generation as the average of the actual generation at the same 4 sites.
3. Calculate the 5-minute variance in solar generation as the difference between the forecast and the actual in every 5 minute period.
4. Calculate the solar variance DESC must respond to as the 15 minute moving average of the 5 minute forecast error<sup>8</sup>.

The result of this analysis is a comprehensive set of data that gives the amount that solar generation varied from the 4-hour forecast. This can be evaluated by season and time period to determine how operators would need to plan for solar uncertainty.

### 3.3 Solar Generation Variability Results

DESC's operators need visibility on the levels of solar at risk of not showing up given the solar generation forecast. To maintain reliability, it is necessary to have sufficient reserves to replace the missing solar generation under the worst-case scenario. The difficulty for operating the system is that DESC not only does not know when solar will generate less than forecasted but also does not want to overestimate the uncertainty and then hold more reserves than needed, which would increase costs. The uncertainty that needs to be estimated is the likelihood and worst case for solar generating less than forecasted given the amount of solar that is expected to be on the system.

<sup>7</sup> <https://www.nrel.gov/grid/solar-integration-data.html>

<sup>8</sup> DESC must meet NERC Reliability Based Control Standards which give the utility up to 30 minutes to respond to any large deviation between load and generation. 15 minutes is chosen for this study as DESC would want to respond well before 30 minutes to ensure sufficient time to avoid exceeding the 30 minute limit.



## Cost of Variable Integration

One outcome of this analysis is that the level of solar variability depends the amount of solar that is generating. At a high level, the higher the percentage of total installed capacity of solar that is generating, the lower the proportion of generation that is at risk.

Table 8 shows the full results of this analysis. The rows give the forecasted solar generation as a percentage of installed capacity. The columns give the percentage drop in solar generation. The cells give the conditional probability of a given drop in solar generation given the level of forecasted generation.

For example, if 1000 MW of solar was installed on the system and it was forecasted to generate 400 MW, the highlighted cells show:

- There is a 1% chance of a 75% drop – equivalent to 300 MW of solar not showing up (only 100 MW is generated).
- There is a 9% chance of a 25% drop- equivalent to 100 MW of solar not showing up (only 300 MW is generated)

**Table 8. Conditional Probability of Solar Variability**

Forecasted Generation	>75% Drop	>65% Drop	>55% Drop	>45% Drop	>35% Drop	>25% Drop	>15% Drop	>5% Drop
20%	0%	1%	4%	6%	9%	16%	23%	33%
25%	1%	2%	4%	5%	8%	13%	21%	33%
30%	1%	2%	3%	6%	9%	13%	22%	34%
35%	1%	2%	4%	7%	11%	16%	22%	33%
40%	1%	1%	2%	3%	5%	9%	16%	27%
45%	0%	1%	1%	2%	4%	8%	13%	22%
50%	0%	1%	1%	2%	4%	7%	12%	25%
55%	0%	0%	0%	1%	1%	2%	6%	16%
60%	0%	0%	0%	0%	0%	1%	3%	11%
65%	0%	0%	0%	0%	0%	1%	3%	5%
70%	0%	0%	0%	0%	0%	0%	2%	5%

Since DESC must maintain self-sufficiency, it is necessary to plan for the worst case drops in solar generation. Table 9 gives the solar generation at risk that is used in this study. In each hour, the amount of solar forecasted to generate is calculated and this table is used to calculate the potential drop in solar that the system may need to respond to.



## Cost of Variable Integration

**Table 9. Solar Forecast Uncertainty**

Expected Generation as % of Installed Capacity	Maximum Drop in Generation
< 40%	75%
40% - 50%	65%
50% - 55%	45%
> 55%	25%

### 3.4 Geographic Diversity

An important part of this analysis is to consider geographic diversity when forecasting the solar uncertainty. Even in a service territory as geographically compact as DESC, spreading solar generation geographically can reduce the uncertainty.

Without considering geographic diversity, the solar uncertainty would be much higher. To avoid this, the forecast error analysis was completed using NREL data located at four points around the DESC territory chosen to be near load centers. Averaging the forecast error among multiple locations properly accounts for the expected geographic diversity of solar resources being added to the system. This ensures that the analysis is not too aggressive in estimating the additional reserves needed by DESC.

The table gives an example of the expected probability of losing solar generation when operating at 50% of maximum generation for the average of the four NREL points used, and for a single NREL point located near Columbia. The key result is that the uncertainty is significantly higher when estimated at a single point.

**Table 10. Impact of Geographical Diversity on Solar Uncertainty**

NREL Location	Forecasted Generation	>75% Drop	>65% Drop	>55% Drop	>45% Drop	>35% Drop	>25% Drop	>15% Drop	>5% Drop
<b>DESC Avg.</b>	<b>50%</b>	0.1%	0.6%	1.1%	2.1%	3.4%	7.4%	12.9%	21.8%
<b>Columbia, SC</b>	<b>50%</b>	3.2%	4.2%	5.2%	7.3%	10.8%	14.7%	21.3%	35.4%



## Cost of Variable Integration

### 4. DEMONSTRATING THE NEED FOR ADDITIONAL RESERVES

DESC reliability is threatened when there is insufficient system ramping capability to meet potential drops in solar generation while maintaining the required reserves.

#### 4.1 Reliability Challenges without Adding Reserves for Variable Integration

In each hour of the forecast, the following process is used to calculate whether DESC has any reliability issues from solar generation that need to be mitigated.

1. Calculate the total amount of ramping capability on the system.
  - This is the sum of the ramping up capability of online units and the capacity of quick start units that can be turned on.
  - This will be at least the total reserve requirement (240MW) but is typically more depending on how the system is operating.
2. Calculate the potential lost solar generation due to forecast uncertainty.
3. Subtract the lost solar generation from the system ramping capability.
4. Flag any hours in which the minimum reserve requirement is not met as reliability violations.

The table below shows 3 sample hours in which there are reserve shortfalls if the system only requires 240 MW reserves but includes risk of solar generation being out. These sample hours are the reason that DESC operators must hold more reserves for the solar uncertainty.

Table 11. Example of Hours with Reserve Shortages

Hour	Load	CC Ramp (Gen)	CT Ramp (Gen)	Saluda Ramp (Gen)	Fairfield Ramp (Gen)	Interruptible Load for reserves	Total Reserves Online	Risk of Solar Out	Reserves Shortage after Solar
4/14/21, 3pm	3558MW	55MW (1548MW)	162MW (227MW)	31MW (163MW)	0MW (0MW)	100MW	347MW	191MW	84MW
9/16/24, 3PM	4196MW	72MW (991MW)	158MW (174MW)	185MW (9MW)	0MW (576MW)	100MW	622MW	432MW	50MW
8/1/25, 4PM	4721MW	0MW (1778MW)	204MW (128MW)	10MW (184MW)	432MW (144MW)	100MW	458MW	286MW	68MW

While in most hours there are more than the minimum reserves, there are a material number of hours in each scenario for which additional reserves would need to be held for the solar generation.

PROMOD was used to simulate the system operation in each solar penetration scenario and the number of hours in the forecast period in which DESC was not holding sufficient reserves to account for solar



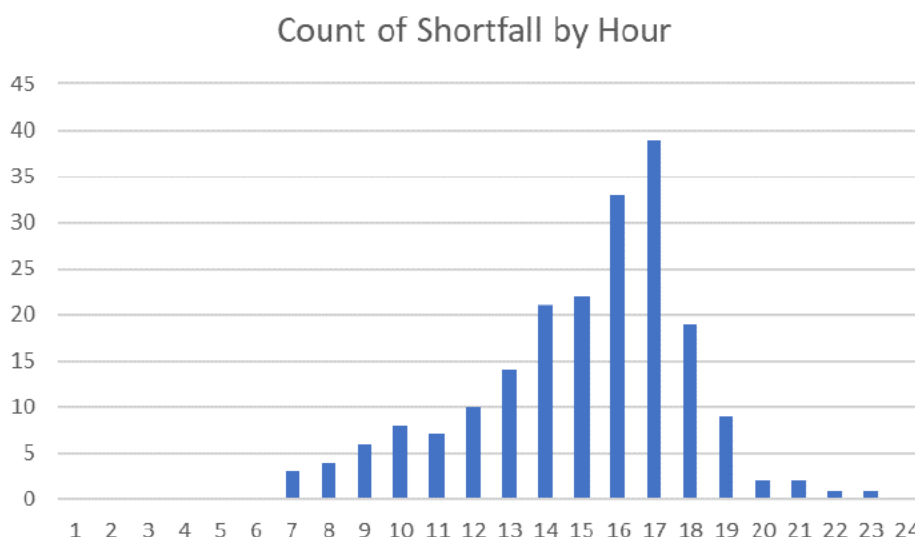
## Cost of Variable Integration

uncertainty was calculated. In both scenarios, the hours with insufficient reserves occurred in all seasons across the year.

- Initial Solar Case – 74 hours
- All Solar Case – 196 hours

Figure 9 shows the distribution by hour of the reserve shortfalls. These hours are concentrated during the evening when solar is ramping down.

**Figure 9. Reserve Shortfalls by Hour in All Solar Case**



## 4.2 Calculating the Additional Reserve Requirements

The analysis in Section 4.1 demonstrates that if DESC does not hold additional reserves then there will be a significant number of hours in which reliability violations occur. That analysis does not show the amount of additional reserves that must be held.

When planning operation, DESC only knows the forecast for solar generation and must plan for the worst case. This means that the utility must hold sufficient reserves in each case to be able to respond to the worst case drop in solar given the forecast.

For each solar penetration scenario, the maximum expected drop in solar generation for each year was used to determine the extra operating reserves that need to be held to ensure that the reserve requirements are met. The reserve requirement changes by year rather than month because the maximum in each month is nearly constant.



## Cost of Variable Integration

Table 12 shows the maximum additional reserves needed in both solar penetration scenarios plus the BAU level of reserves held by DESC.

**Table 12. Maximum Additional Reserves Needed**

Year	BAU	Initial Solar	All Solar
2020	240	348	529
2021	240	349	579
2022	240	351	581
2023	240	352	582
2024	240	354	584
2025	240	356	586
2026	240	358	588
2027	240	360	590
2028	240	363	593
2029	240	365	595
2030	240	368	598
2031	240	371	601
2032	240	375	605

One aspect of holding reserves is that DESC knows the level of expected solar generation prior to setting the reserves to be held, so the required reserves needed to compensate for a potential drop in solar would be adjusted on a daily or hourly basis.

Table 12 shows the maximum needed reserves necessary, but when calculating the costs it is important to consider that many individual days within each case have lower forecasted solar than the maximum and hence need fewer reserves.

For the All Solar Case, the analysis shows:

- All Solar level of reserves is needed for 38% of the days
- Intermediate level of reserves is needed for 51% of the days<sup>9</sup>
- Initial Solar level of reserves is needed for 12% of the days

<sup>9</sup> The intermediate level of reserves is between the All Solar and BAU requirements. It is calculated for days in which solar generation at a moderate level.



## Cost of Variable Integration

To ensure that the analysis does not overestimate the costs to integrate the All Solar reserves, PROMOD was run with each of these levels of reserves and then the results were blended using the weighted average of costs tied to the number of days that each level of reserves was required.



## 5. MITIGATION OPTIONS AND INTEGRATION COSTS

### 5.1 Potential Mitigation Options

The mitigation needed to integrate solar generation is to hold additional reserves that will be available if actual solar generation is less than forecasted. There are two broad mechanisms for DESC to do this:

1. Operate the existing system differently so that there are more operating reserves.
2. Procure quick-start resources such as battery storage or CT gas units that will be able to provide reserves even when offline<sup>10</sup>.

In this analysis, the cost of holding additional reserves is calculated first. This is then compared to the cost of adding new resources to check whether there is a lower cost approach to procuring the needed reserves. The integration cost for the solar resources is the levelized cost difference of the system costs with and without additional reserves.

Discussed in Section 5.4 is a third option in which the solar projects can add storage or operate in such a way that DESC's reserve requirements do not increase. If a project can meet the requirements to ensure this, then it is appropriate to exclude any integration impacts from the analysis of the avoided costs for that specific project.

### 5.2 System Impacts of Holding Additional Reserves

In most hours, especially overnight, DESC holds more than the minimum necessary reserves through their least-cost security constrained dispatch. This means that adding to the reserve requirement in the simulation does not materially influence the system operation in those hours. However, in hours in which DESC holds the minimum or close to the minimum amount of reserves, some resource generation levels will have to be changed.

PROMOD solves for the least-cost dispatch while respecting the additional reserve requirements. To a large extent, additional reserves come from reducing the generation from CC units so that they are providing more flexibility. ST units are turned on to ensure that load can be met. Figure 10 shows the comparison of the starts per month in case SC2 with and without additional reserves being held. As would be expected, the cycling increases with the additional reserves as the CTs and STs must turn on to be available<sup>11</sup>.

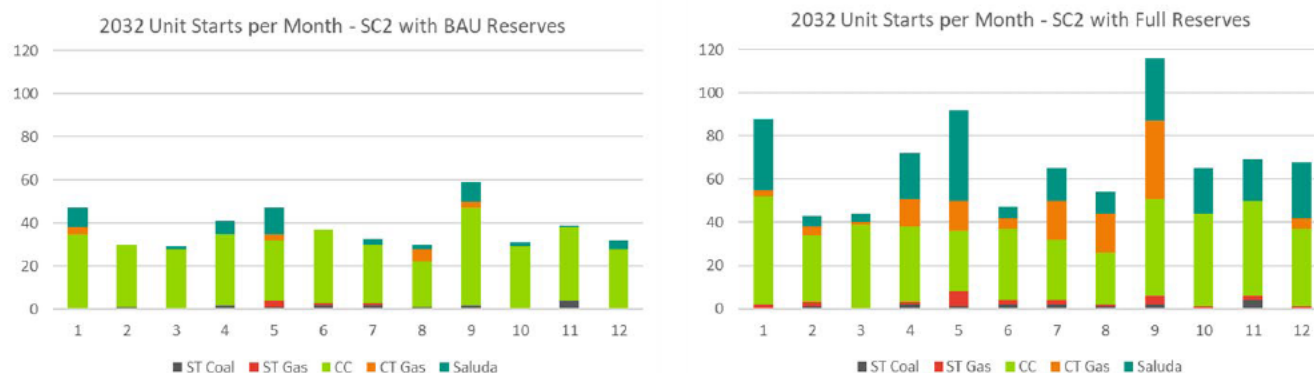
<sup>10</sup> Note that there are methods for solar units to provide flexibility and ramping to the system. Although this may be a feasible alternative in the future, this possibility has not been considered in this analysis because DESC cannot implement it unilaterally but only with technological changes by the solar facility owners.

<sup>11</sup> Note that Saluda is allowed to cycle more in the alternate case than according to the current operating agreement. This is a **conservative** assumption. If Saluda were more limited as per the current operating agreement, then other units would have to make up the difference and integration costs would increase.



## Cost of Variable Integration

**Figure 10. Comparison of Unit Cycling**



To a large extent, the driver of the integration costs are increased fuel and operating costs. This is because less efficient units must be online to provide energy, units must operate at less efficient power levels, and there are increased start-up costs due to additional cycling.

One point of conservatism in this analysis is that there are additional maintenance and fuel costs from ramping generating resources up and down very quickly when renewable generation varies. This analysis only considered the costs to maintain reserves and excluded the costs from the additional stress and reduced efficiency from matching short-term variability of solar generation.

### 5.3 Cost of Holding Additional Reserves without Other Changes

As described, the cost of holding additional reserves is calculated by comparing the PROMOD production costs with and without holding additional reserves required to meet solar uncertainty.

One concern is to ensure that there is no double counting with the costs reported in the PR-1 and PR-2 avoided cost study. In that study, there are increased costs from Energy Not Served and Reserve Deficits. A side-benefit of holding additional reserves for variable integration is that both Energy Not Served and Reserve Deficits would likely be decreased. Conservatively, for this study, the entire cost of Energy Not Served (\$0.68/MWh) and the entire cost of Reserve Deficits (\$0.28/MWh) are assumed to be eliminated with the extra reserves needed for solar.

The comparison of system production costs in the two solar penetration scenarios are given in Table 13. The Net Present Values (NPV) are calculated over a 15-year period (2020 – 2034) using DESC's discount rate of 7.9%. As discussed previously, while the first tranche of contracted solar does cause costs to the system, there is no term in those contracts to apply these costs. The second tranche of contracted solar does have a contract term for these costs. The result is that the incremental costs for the second tranche of solar is calculated independently.



## Cost of Variable Integration

Table 13. Cost to Integrate Variable Generation

	Initial Solar	All Solar	Incremental All solar
<b>Cost Difference NPV (2020 \$)</b>	\$21,441,812	\$73,242,219	<b>\$51,800,407</b>
<b>Solar Generation NPV (MWh)</b>	6,091,424	18,495,510	<b>12,504,086</b>
<b>Levelized Cost (2020 \$/MWh)</b>	\$3.52	\$3.96	<b>\$4.14</b>

The breakdown of the cost drivers in SC2 are shown in Table 14. The majority of costs are from additional fuel cost costs but VOM and start-up costs are also material increases in system costs.

Table 14. Breakdown of Incremental Costs in All Solar Case

	VOM	Fuel	Emission	Start-up	Total
<b>Cost Difference NPV (\$)</b>	\$13,941,615	\$40,320,211	\$48,760	\$19,103,954	\$73,242,219
<b>Generation NPV (MWh)</b>	18,495,510				
<b>Levelized Cost (\$/MWh)</b>	\$0.75	\$2.18	\$0.003	\$1.03	\$3.96
<b>% of Total Cost</b>	19%	55%	0%	26%	100%

## 5.4 Alternative Variable Generation Integration Approaches

In the All Solar Case, the NPV of the cost of holding additional reserves for variable integration is \$73.2M driven by the need for an additional of ~350MW of reserves. The two alternatives to adding additional reserves are either for DESC to add resources that provide the reserves or for the solar projects themselves to add storage or operate more flexibly.

### 5.4.1 DESC adds Resources

If DESC can add resources that can provide these reserves for less than incremental cost, then it would be possible to reduce the overall integration costs of solar to the system. For providing reserves, the best options are quick-start gas CTs or battery storage. This study considered the following resources and costs:

- Quick-start CT - \$700/kW overnight cost



## Cost of Variable Integration

- 1-hour Lithium-Ion Battery - \$800/kW overnight cost<sup>12</sup>
- 2-hour Lithium-Ion Battery - \$1000/kW overnight cost

At a high level, this implies that DESC could alternatively add ~110 MW of quick-start CT, ~95 MW of 1-hour battery, or ~75 MW of 2-hour battery at the same cost incurred by carrying more reserves<sup>13</sup>. None of these capacities would be sufficient to meet the additional reserve requirements of the solar generation<sup>14</sup>.

While additional resources are not currently feasible for reducing integration costs in any of the solar penetration scenarios, DESC should continue to monitor the need for reserves and the technology costs of mitigation options. The ability to provide reserves with batteries or CTs caps the integration cost of solar to the cost of new resources. If batteries decline in price more sharply than expected, they may become a feasible mitigation even with the SC2 levels of solar during this study period<sup>15</sup>.

### 5.4.2 Solar Projects add Storage or Operate Flexibly

There are several ways by which a solar project can operate with sufficient flexibility so that DESC does not need to add reserves. If the project does this, then it is appropriate for DESC to calculate the avoided cost for that specific project without adding any additional reserve requirements. The key issue is that the avoided costs will be different for a project that can operate flexibly vs. a traditional solar installation without the ability to operate flexibly.

The following some high level capabilities for a solar or solar plus battery project to not cause DESC to need to increase the reserves being held:

- DESC has some ability to control the dispatch of the generation from the project.
- Be able to replace enough of the nameplate capacity of the project when called upon to make up for generation lower than forecasted.
- Be able to maintain the replaced generation for sufficient time to avoid reliability challenges.

Co-locating an appropriately sized battery with the storage project is one possibility for meeting these requirements. Another option is "flexible solar" which is an operating mode in which the solar project can be dispatched up and down by the system.

It is appropriate and necessary for DESC to work with solar project owners to determine options for ensuring that the requirements can be met.

<sup>12</sup> Note that this cost assumes technology improvement and cost declines through 2025

<sup>13</sup> It may be cost-effective to add resources for other purposes such as energy or capacity that have the added benefit of adding reserves to the systems that would reduce overall operating costs.

<sup>14</sup> To do a full analysis of mitigation with additional resources it would be necessary to also calculate additional benefits and costs associated with owning and operating these resources. The current analysis is only a screening to demonstrate that the additional of these resources is not able to reduce the overall integration costs.

<sup>15</sup> Note that if solar units were operated to provide flex bility to the system, the integration costs borne by DESC would be reduced.



## APPENDIX A. MARKET MODELING PROCESS

Navigant's market modeling approach relies on a multifaceted approach for modeling and simulating the energy market and studying the performance of energy assets in the marketplace. Navigant's approach relies on the involvement of numerous subject matter experts with specific knowledge and understanding of several fundamental assumptions, such as fuel pricing, generation development, transmission infrastructure expansion, asset operation, environmental regulations, and technology deployment. From our involvement in the industry, Navigant has specific and independent views on many of these fundamental assumptions based on our knowledge and understanding of the issues. Provided below is an overview of the modeling process.

### A.1 Electric Market Simulation

A diagram depicting the models used in Navigant's market modeling can be seen in Figure A-1. Navigant's proprietary Portfolio Optimization Model (POM) is a linear optimization model used for capacity expansion. POM simulates economic investment decisions and power plant dispatch on a zonal basis subject to capital costs, reserve margin planning requirements, RPS, fuel costs, fixed and variable operations and maintenance costs, emissions allowance costs, and zonal transmission interface limits. This model incorporates the same generation base, demand forecasts, fuel prices, other operating costs, and plant parameters that are utilized throughout the market simulation modeling process. The model simultaneously performs least-cost optimization of the electric power system expansion and dispatch in multi-decade time horizons. POM can perform multivariate optimization, which can consider value propositions other than cost minimization, such as sustainability, technological innovation, or impacts on other sectors, such as natural gas. The generation expansion results from POM are used in the fundamental energy price forecast.

Navigant uses PROMOD, a commercially-available software, to develop its wholesale energy market price and plant performance forecasts. PROMOD is a detailed energy production cost model that simulates hourly chronological operation of generation and transmission resources on a nodal basis in wholesale electric markets. PROMOD dispatches generating resources to match hourly electricity demand, dispatching the least expensive generation first. The choice of generation is determined by the generator's total variable cost given operating constraints such as ramp rates (for fossil resources) or water availability (for hydraulic resources), and transmission constraints. The total variable cost of the marginally dispatched unit in each hour sets the hourly market clearing price. All generators in the same market area that are selected to run receive the same hourly market clearing price adjusted for losses and congestion, regardless of their actual costs. The LMP's produced by PROMOD compose Navigant's structural market price forecasts. Navigant does not employ bid-adders or other exogenous adjustments to prices in the PROMOD forecast.

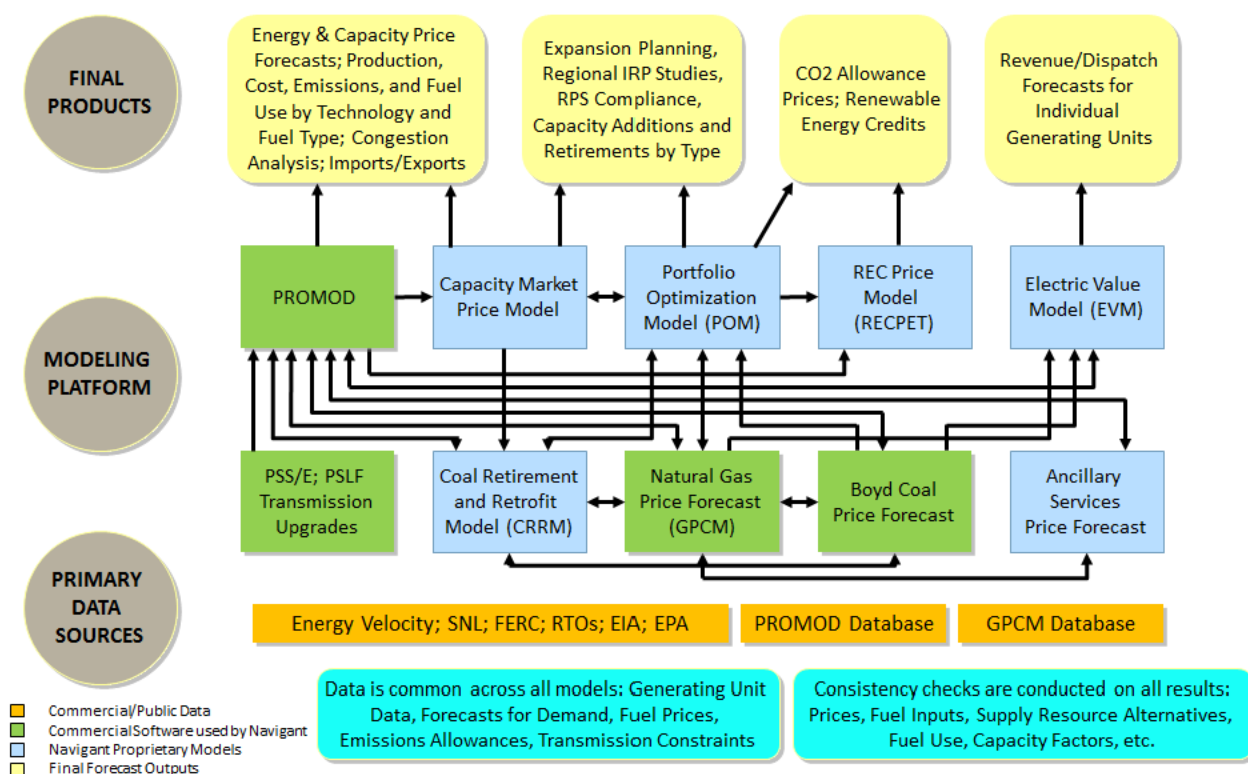


## Cost of Variable Integration

Within PROMOD, production costs are calculated based upon heat rate, fuel cost, and other operating costs, expressed as a function of output. Physical operating limits related to expected maintenance and forced outage, start-up, unit ramping, minimum up time and downtime, and other characteristics are factored into the simulation. Supply offer prices are simulated for each unit within PROMOD that correspond to the minimum price the unit owner is willing to accept to operate the unit. For most generation resources, offer prices are composed primarily of incremental production costs. Incremental production cost is calculated as each unit's fuel price multiplied by the incremental heat rate, plus variable operations, emissions, and variable maintenance costs.

Where relevant (primarily for thermal units), the unit offer price also incorporates the unit's start-up and no-load costs. The start cost component includes fuel costs and other operating costs encountered in starting the generating unit, beyond those reflected in the heat rate and variable operating cost assumptions. The no-load cost reflects the difference between average and incremental fuel costs for generating stations that are dispatched at less than full output.

**Figure A-1. Navigant's Market Simulation Modeling Process**



Source: Navigant

PROMOD has several distinguishing features that qualify it for application in electric power forecasting and related studies. These features include the following:

- Individual transmission line modeling



## Cost of Variable Integration

- Detailed and flexible unit commitment and dispatch modeling
- Modeling of operational transmission constraints (e.g., operating nomograms)
- Calculation of security-constrained dispatch schedules
- Hourly modeling of loads and resource operation

When preparing market price forecasts, Navigant first forecasts a fundamental, or structural, hourly energy price series for the applicable node or zone using PROMOD. Structural prices represent expected day-ahead market clearing prices under conditions of perfect foresight about load, generator and transmission availability, and fuel costs. As such, they lack information about additional price volatility in the market that can stem from intra-month volatility in fuel and emissions prices, stochastic variations in demand, and deviations of market bidding away from marginal cost bidding. In order to account for this missing volatility and any model error, Navigant incorporates adjustment factors to correlate power price volatility from simulated ex post “backcasts” in PROMOD with historical volatility experienced in the market. Using benchmarks derived from historical data for a rolling three-year period, the PROMOD hourly price forecasts are adjusted to account for the relative difference between actual market prices and PROMOD’s (simulated) prices by season and time period. The actual prices and the simulated prices are grouped and averaged in 18 time blocks differentiated by season (summer, winter, shoulder) and time-of-day (4 hour blocks corresponding to off-peak and peak periods). After eliminating historical price spikes deemed to be unpredictable (two standard deviations outside the time-block average), time-block ratios of actual prices to simulated prices are used to adjust the PROMOD forecast, and these are the final adjusted market prices provided in this report.

Navigant also uses GPCM to develop our Reference Case Gas Price Forecast. GPCM is a commercial linear-programming model of the North American gas marketplace and infrastructure. Navigant applies its own analysis to provide macroeconomic outlook and natural gas supply and demand data for the model, including infrastructure additions and configurations, and its own supply and demand elasticity assumptions. Forecasts are based upon the breadth of Navigant’s view, insight, and detailed knowledge of the US and Canadian natural gas markets. Adjustments are made to the model to reflect accurate infrastructure operating capability and the rapidly changing market environment regarding economic growth rates, energy prices, gas production growth levels, demand by sector and natural gas pipeline, storage, and LNG terminal system additions and expansions. To capture current expectations for the gas market, this long-term monthly forecast is combined with near-term New York Mercantile Exchange average forward prices for the first two years of the forecast.